Relationship Between Hydrocarbon Accumulation and Geopressure and Its Economic Significance

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Log-calculated formation pressure data, reflecting the favorable or unfavorable nature of hydrocarbon environments, can be used to predict whether accumulations are commercial or noncommercial and also the type of hydrocarbon present. This knowledge is vital in making such economic decisions as whether to set pipe and continue drilling or to plug and abandon and turn the money to better use.

Introduction

Many published descriptions of drilling and production problems in overpressured formations — and probably many more that have not been widely published — demonstrate that geopressures are apparently not peculiar to any specific part of the world. In a published paper[1] we have already discussed areas of geopressure that had been reported earlier.

Scattered throughout the literature are well data presenting maximum geopressures encountered in the drilling for and production of oil and gas. It is not in the scope of this paper to present a complete or even partial listing of these data. However, in connection with our present study it is of special interest to take a closer look at the magnitude of geopressures encountered in the Gulf Coast over the last few years since improved drilling techniques have enabled us to drill more efficiently in these highly pressured environments. Such environments and areas have been avoided previously because of associated drilling and completion problems and high costs.

As early as 1938, Cannon and Craze[2] presented the relationship of pore pressure to depth in the Gulf Coast area of Texas and Louisiana, reporting maximum pressure gradients approaching 0.765 psi/ft. A few years later, in 1943, in a study of abnormal saltwater pressures on the Texas and Louisiana coast, a maximum pressure gradient of 0.83 was quoted by Denton.[3] Only 3 years later, in subsequent observations in the Gulf Coast area by Cannon and Sullins[4] the estimate of maximum pressure gradient was increased to 0.865 psi/ft.

Dickinson,[5] in 1953, quoted values as high as 0.872 psi/ft, and concluded that "these gradients appear to indicate that the upper limit of abnormal pressure gradients is being approached, and that it is unlikely that it will exceed about 0.90 pound per square inch per foot depth."

Since then several oil companies have encountered higher pressure gradients than quoted by Dickinson; however, most of the literature indicates that the majority of the commercial hydrocarbon accumulations still appear to be associated with geopressures up to about 0.85 psi/ft. For example, Fowler[6] states that the "only systematic difference observed between commercial, and barren or non-commercial, abnormally pressured pay sands in Chocolate Bayou [Brazoria County, Tex.] is a difference in pressure gradient. Sands with commercial hydrocarbon accumulations have pressure gradients less than about 0.85 psi/ft; sands with pressure gradients greater than about 0.85 psi/ft, do not contain commercial hydrocarbons."

A quite similar high pressure gradient has been reported in a reservoir on the north flank of the Egan field, Acadia Parish, La.[7] With an initial pressure gradient of 0.84 psi/ft, the subject reservoir produced 6 billion cu ft of gas, 170,000 bbl of condensate and 1 million bbl of salt water over a period of 6½ years.

More recently, Classen[8] published some formation pressure-production relationships for the area around the Lake Mongoulois dome in central St. Martin Parish, La. Production has been found in pressure

environments ranging from hydrostatic to about 0.90 psi/ft. With the distribution of hydrocarbons directly related to the geostatic pressure "normal pressure zones yield oil production on the east and north flanks. On the southeast flank, an intermediate (but high) pressure zone yielded dry gas."

In our experience on the Gulf Coast, as we shall discuss in more detail later, we also have encountered some commercial accumulations of hydrocarbons in geopressure environments as high as 0.88 psi/ft. However, with the existence of such supergeopressures, the presence of commercial gas or oil reservoirs becomes the exception rather than the rule.

Similar data — generally unnoticed, it seems — appeared in the literature as early as 1949. McCaslin[9] cited two wells in the Four Isle field in Terrebonne Parish, La., that reportedly showed pressure gradients of 0.955 and 0.984 psi/ft while being drilled to 14,564 and 13,230 ft, respectively. In reporting additional data from a high-pressure oil well in the Mississippi Delta area he stated that "on official state potential test, the well registered a flowing tubing pressure of 7900 psi while flowing 157 bbl of 38°API gravity crude in 24 hours on a ³⁄₃₂ in. choke. Production is being obtained from an open-hole interval, 12,994-13,050 ft. The calculated original bottom-hole pressure for this zone was 12,635 psi at 13,000 ft." If these data are correct, the pressure gradient in this well may be as high as 0.975 psi/ft. Based on our experience in the Gulf Coast area, this value, which closely approaches overburden pressure, appears to be the highest pressure gradient ever encountered in a pay zone in this region.

To our knowledge, there are several oil wells in the Middle East and in the Khaur field of India that exhibit similar high pressure gradients, those in the latter being as high as 0.98 psi/ft. The lithologic and geologic environment of the formations, however, is not comparable with that of our Gulf Coast area.

The Geopressure-Hydrocarbon Relationship And Its Importance in Decision-Making

Experience in the Gulf Coast area indicates that subsurface pressure and temperature conditions, and diagenesis of clayey sediments appear to have an important relationship to the distribution of petroleum hydrocarbons such as oil and gas. It has been well established that subsurface heat conductivity can be affected by numerous factors such as salt domes and salt ridges, formation dip and relief, petroleum and ore deposits, intrusions having a low heat conductivity, faults, type of rock, and porosity. Recently, several authors[1,10] have recognized and discussed some rather important relationships between geopressures and formation temperature. It has also been noted that geothermal gradients become very steep in shale formations immediately overlying overpressured aquifers or potential reservoir rocks. Gradients in the range of 3° to 6°F/100 ft have been reported. Bearing this in mind, several operators, while drilling, routinely measure mud flowline temperature to detect any early warning of geopressure.

Fig. 1 shows the pressure-temperature relationship in about 60 wells in the Gulf Coast area. The formations range from slightly overpressured to superpressured, with some of the pressure gradients exceeding 0.9 psi/ft. Corresponding petroleum reservoir temperatures as high as 365°F have been recorded.

It is interesting to note that a temperature range of 225° to about 285°F does seem to coincide with the range of the highest geopressure gradients encountered in hydrocarbon-bearing reservoir rocks. This temperature range lies in the bulk part of the second stage of dehydration during diagenesis of clayey sediments, as proposed by Burst[11]: ". . . the amount of water in movement during the second stage at a level which does intersect this interval, is 10-15% of the compacted bulk volume and represents a significant fluid displacement capable of redistributing any mobile subsurface component. The movement appears to occur in a relatively restricted depth-dependent temperature zone. . . ."

It is also notable that with further increasing formation temperature the magnitude of geopressure gradients seems to reverse its trend and to decline in potential reservoir rocks. This coincides with a simultaneous percentage increase in the accumulation of gas. An additional related factor is probably the thermal cracking action in this type of environment. At the same time, extremely high gradients are encountered in high-temperature aquifers (Fig. 1). Since the correlation is based on only 60 wells, we realize the possible need for some modifications.

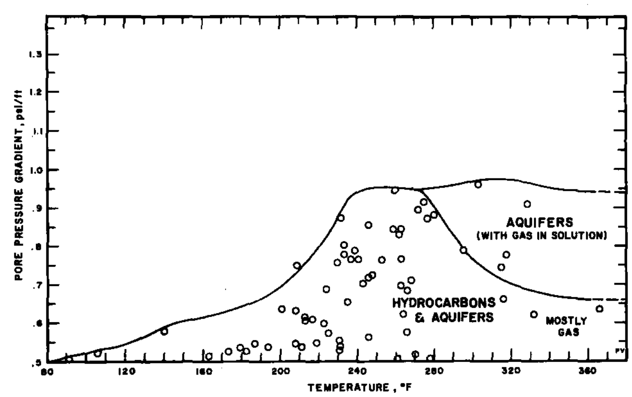

Fig. 1—Pressure-temperature relationships for wells in Gulf Coast area.

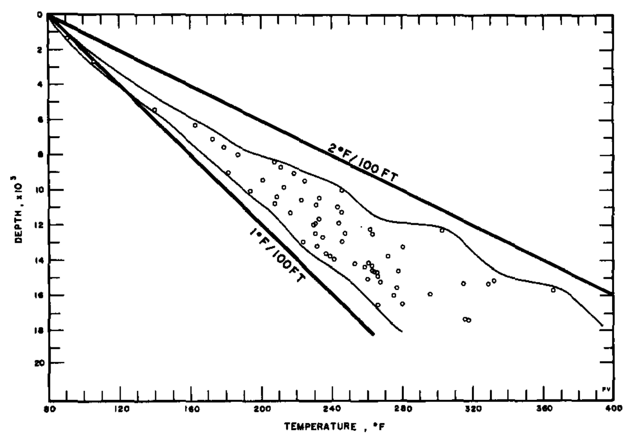

Fig. 2—Temperature-depth relationships for wells plotted in Fig. 1.

Fig. 2, which gives the temperature-depth relationships for the same wells, shows that the average rate of increase varies with different wells from less than 1°F/100 ft to about 1.8°F/100 ft, provided a constant temperature gradient is assumed. However, the temperature gradients are not necessarily uniform with depth. They are commonly higher in formations with abnormally high pore pressures and lower where the sand:shale ratio is high and associated pressure gradients are lower.

Fig. 3 shows the increase of pore pressure with depth for all wells studied. Note the rather drastic increase in the pressure environment for depths of 8,000 ft and deeper. Assuming a constant overburden pressure of 1.0 psi/ft, formations below 14,000 ft may approach this overburden gradient.

It is well known that, depending on the thermodynamic conditions, hydrocarbon systems may occur as solids, liquids, gases, or mixtures of them. Regional investigations of U. S. and Russian reserves of oil and gas show that, at considerable depths, reserves of gas do exceed proved reserves of oil. Conditions seem to be similar for overpressured formations in the Gulf Coast area, since the highest pressure gradients are generally in the deepest environments.

In Fig. 4, we have attempted a generalized correlation between a "typical" Gulf Coast shale resistivity profile, which can be correlated with the magnitude of geopressures, and the distribution of oil and gas fields. For the sake of simplicity and generalization, we have omitted both the depth and shale resistivity scales, realizing that such a typical profile may very well change with local environments.

This typical profile plot is based entirely on the Short Normal curve and does not apply to any other resistivity (conductivity) measuring device. We have developed this relationship with the Short Normal curve because we believe it is the most accurate resistivity tool to define quantitative pressures since it is an uncorrected raw-data curve. Also, it is the log most available for wells in the Gulf Coast area. However, if enough logs are available, similar relationships could be developed from acoustic velocity log data. We do not recommend the use of the induction resistivity or conductivity log since it does not yield a raw-data curve and different service companies apply different corrections for signal attenuations in high-conductivity ranges (as in high-pressure environments).

In determining favorable hydrocarbon environments we have had considerably more success using this shale resistivity profile rather than the actual pressure gradients or required mud weights as most people have attempted. Since the literature has indicated commercial producing gradients that approach 1.0 psi/ft, a gradient of 0.85 psi/ft may be a reasonable cutoff for commercial production in one area but not in another. For example, we have found no com-

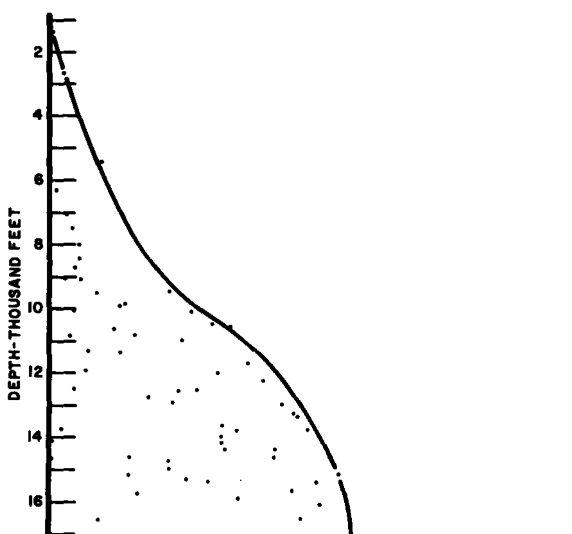

Fig. 3—Relationship between pore pressure and depth.

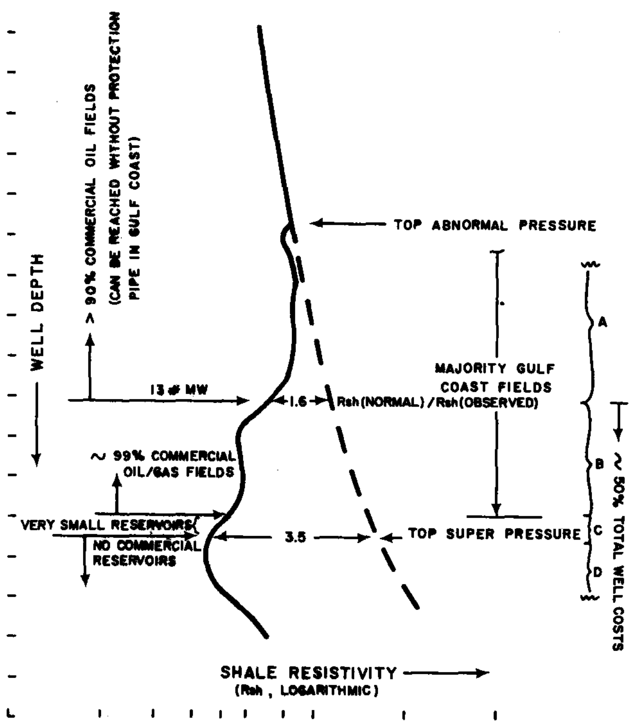

Fig. 4—Typical Gulf Coast shale resistivity profile.

mercial reservoirs within and below the well depth where the ratio of extrapolated resistivity to measured resistivity reaches 3.5, irrespective of the pressure gradient.

Fig. 5 is the plot of the shale resistivity ratios vs average pressure gradients as developed by Hottman and Johnson.[12] Note that for a shale ratio of 3.0, the pressure gradient from the Hottman and Johnson average line would be 0.86 psi/ft. However, the actual data vary between about 0.83 and 0.92 psi/ft. Therefore, this average trend line must be modified for different localities; otherwise, the log-determined gradient is subject to some error. Also shown on Fig. 5 is a relationship we have developed for a particular area in East Cameron. We have not encountered any production within and below the well depth where the shale ratios reach 3.5; therefore, application of the log-calculated gradient, unless modified for particular areas, would be misleading. For this reason, we have used the ratio approach rather than the empirically determined pressure gradient with its inherent errors.

Commercial Oil Fields

Most of the oil pay zones in the Gulf Coast area can be reached without protection pipe. Statistical data have shown that 90 percent of the commercial oil fields will probably be found in a pressure environment up to about 13 lb/gal, corresponding to a shale ratio of 1.6. The use of mud weights exceeding 13 lb/gal generally requires that a string of protection pipe be set to avoid lost circulation or differentially stuck drill pipe.

Commercial Oil and Gas Fields

Approximately 99 percent of all commercial oil and gas reservoirs are found in Zones A and B as plotted on Fig. 4. This observation is of great economic significance since the cost of successfully completing wells in high-pressure formations may become exceedingly high. It is a matter of record that in drilling a well the highest proportion of money is usually spent on the last few hundred feet, where the highest geopressures are generally encountered. Knowing the local or regional relationship between the magnitude of geopressures and the distribution of hydrocarbons, one can make a well-founded decision as to whether or not a well should be deepened further.

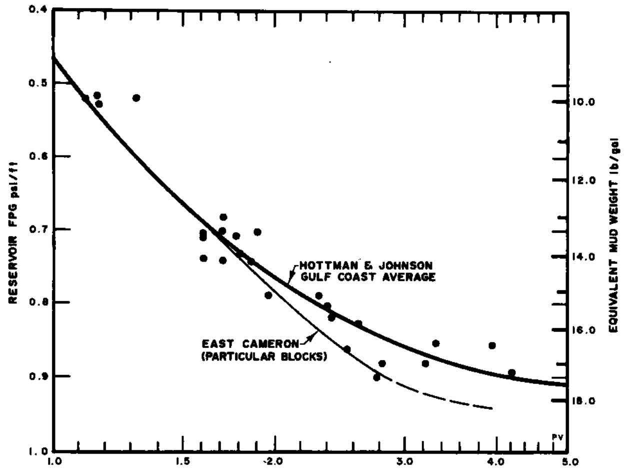

Fig. 5—Relationship between shale resistivity parameter $R_{n(sh)}/R_{ob(sh)}$ and reservoir fluid pressure gradient.

Small Reservoirs

As may be observed from our typical Gulf Coast shale resistivity profile, there appear to be quite a substantial number of commercial oil and gas reservoirs in geopressured environments. However, with increasingly higher geopressures, the potential reservoir becomes areally smaller. The pay may be of limited extent, produced from one- or two-well pools, and generally will fall in or near Zone C (Fig. 4). Often a well that falls in or near Zone C would be commercial by itself; but because it is capable of producing at high rates, offset wells are drilled, and these, because they are generally noncommercial, ruin the economics of the over-all venture. Wells falling in or near Zone C are candidates for detailed reservoir pressure studies to determine the limits of the reservoir so that decisions can be made as to further development.

Noncommercial Reservoirs

In the region of so-called "supergeopressures", indicated as Zone D in Fig. 4, we have not encountered commercial reservoirs. The reservoirs frequently are characterized by extremely high pressures and fast drawdown, indicative of low volume. Furthermore, it is our experience that the majority of reservoir rocks exhibiting supergeopressures will contain only water with some gas in solution. Sidewall cores and well logs taken in such intervals generally make them look favorable for production.

Conclusions

Based on the foregoing observations, the following conclusions are possible: experience indicates that the conventional Short Normal curve can be used to define and determine the distribution of the types of hydrocarbons in the Gulf Coast area. Knowledge of this statistical distribution can be used in making economic decisions such as whether to stop or to continue drilling in a favorable or unfavorable pressure environment.

Field Examples and Case Histories

Fig. 6A is a plot of a discovery well in Vermilion Parish, La. The well was completed in the interval 14,630-14,695 ft — indicated as (1) on the figure — for an initial potential of 8,000 Mcf of gas per day and 648 bbl of condensate on a 16/64-in. choke with a tubing pressure of 6,000 psi. The cutoff ratio of 3.5 was reached at 12,700 ft, which establishes the top of the unfavorable hydrocarbon environment. Two offsets were started to the southwest and northeast soon after the initial completion of the discovery well. The plots of these wells are shown in Figs. 6B and 6C, respectively. By the time the offsets were drilled to the zone correlative with the zone producing in the first well, the pressure in the first well was essentially depleted. The two offsets were dry and the discovery well was recompleted in the thin interval indicated as

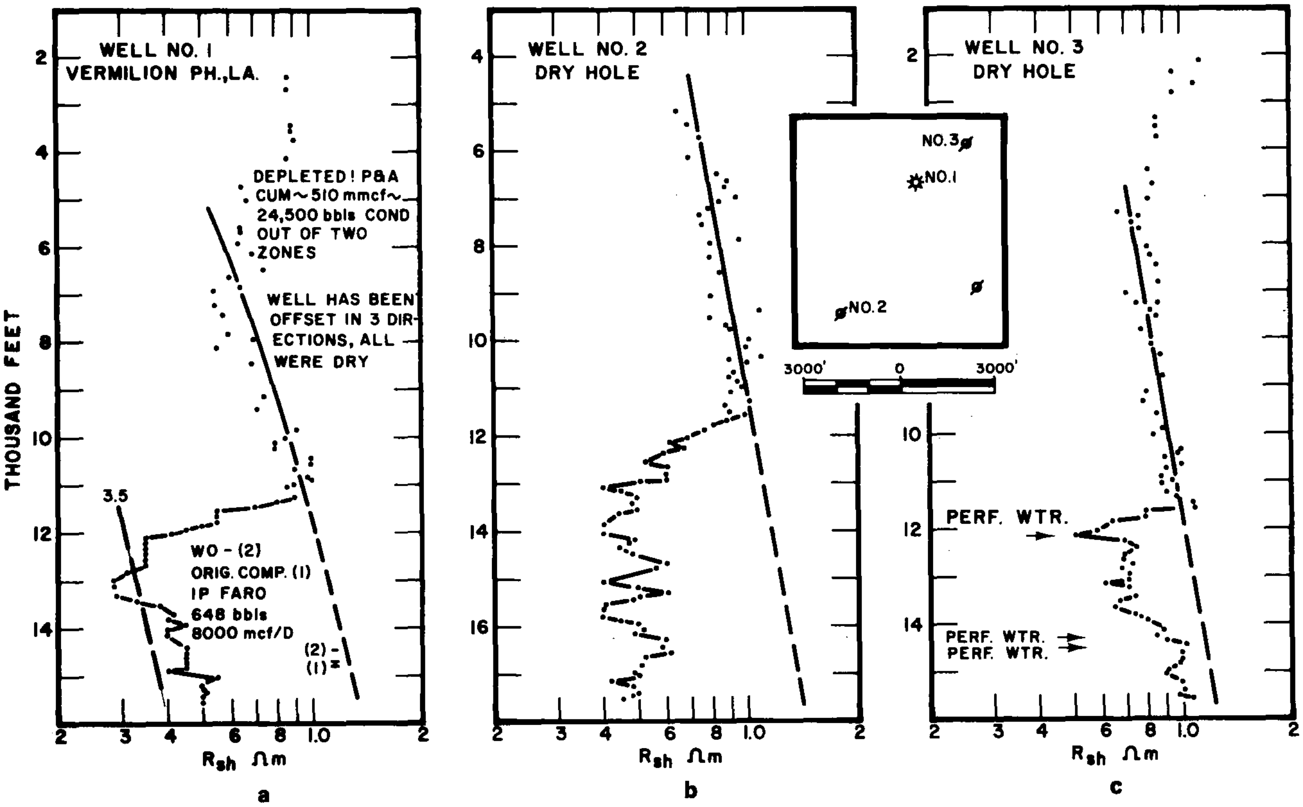

Fig. 6—Limited-size reservoirs, Gulf Coast area.

(2) in Fig. 6A. The effects of this recompletion lasted about 2 months before they also were exhausted. In all, the cumulative production from both zones totaled 510 MMcf of gas and 24,500 bbl of condensate. Needless to say, this was an expensive "discovery" since the total cost of the three wells was in the neighborhood of $3 million. It is interesting to note that Well 3 in Fig. 6C has pore pressures considerably less than those of the discovery well or Well 2. This indicates that Well 3 is in a separate fault block and exhibits pressures quite different from those of the other two wells. There is a good producing field about a mile north of this area.

A completion was attempted at 14,374-14,377 ft and at 14,381-14,385 ft in the well plotted in Fig. 7. These tested intervals are about 1,300 ft below the top of the 3.5-ratio cutoff. The combined zones flowed gas, condensate, and water. The initial BHP was approximately 13,000 psi, declining to 6,200 psi in a matter of hours. A fluid sample taken at the separator consisted of approximately one-third oil, one-third water, and one-third solids. The solids below 2 microns were examined by X-ray diffraction analysis and showed 49 percent mixed layered clays, 26 percent illite, 16 percent chlorite, and 9 percent kaolinite. The cost to test this interval in this unfavorable environment was approximately $200,000.

Fig. 8 is a plot of shale resistivity for a rank wildcat in the Louisiana Offshore area. The well was logged at 13,020 ft after the drilling rate increased with an associated increase in mud flowline temperatures. Mud weight at the time of logging was 11.2 lb/gal. The plot indicates that the pressures were equivalent to approximately 16.3 lb/gal at total depth in a nonpermeable shale section. At this point, it was necessary to decide whether or not to set protection pipe so that drilling could be continued. At the target depth of 16,000 ft there was salt, and it was believed that there was another 3,000 ft of domal and prospective sediments present. The shale ratio at 13,020 ft was 2.8, which exceeded the 1.6 cutoff for an oil environment. Based on this 2.8 ratio, only a gas environment should be expected below 13,020 ft. Furthermore, the facts that the resistivity was de-

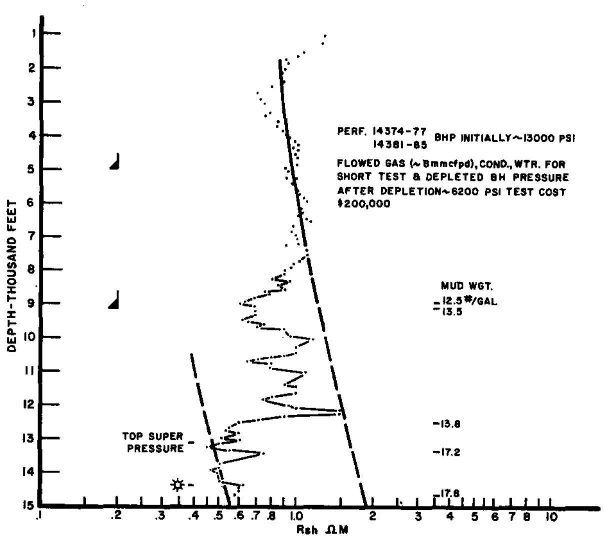

Fig. 7—Fast pressure depletion, Offshore Louisiana.

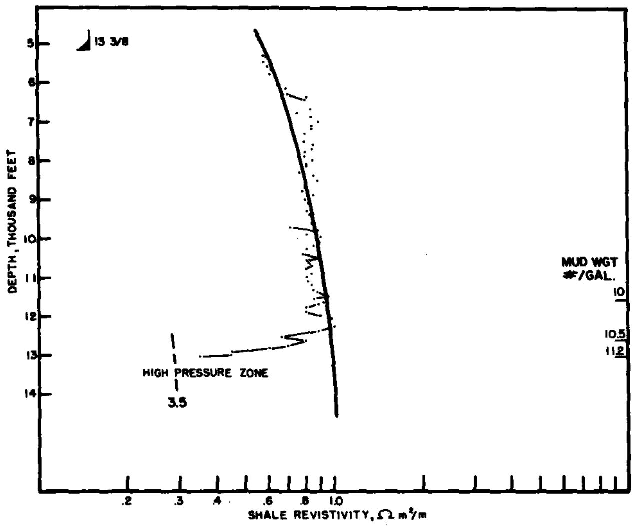

Fig. 8—Rank wildcat, Offshore Louisiana.

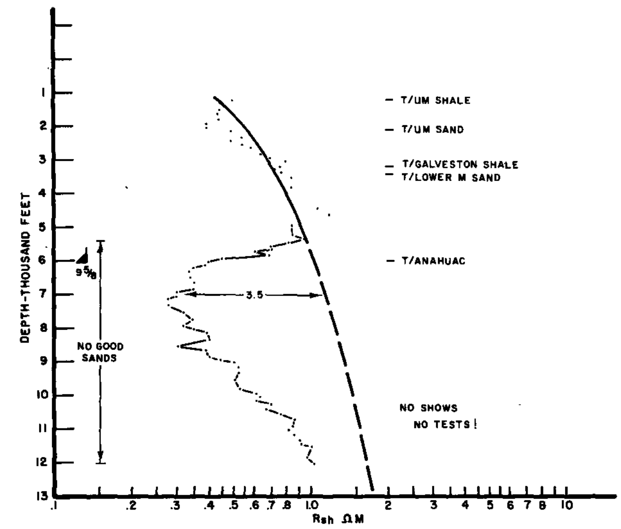

Fig. 9—Well on domal structure, Offshore Texas.

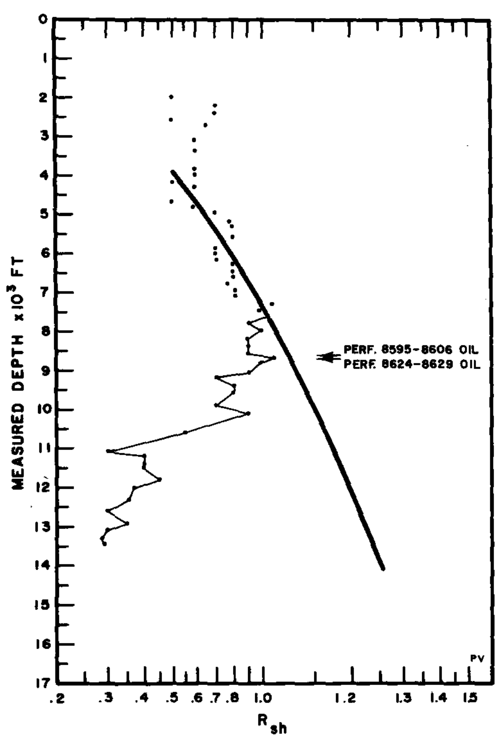

Fig. 10A—Field producer, Offshore Louisiana.

creasing rapidly at 13,020 ft and that the 2.8 was approaching the 3.5 cutoff indicated that an environment unfavorable even for gas would probably be encountered shortly. In this particular case, pipe was set and drilling continued. The cost of setting the casing was approximately $100,000. Almost immediately, the well unexpectedly drilled into salt.

Fig. 9 gives data on a well that was drilled offshore Aransas County, Tex. Note that the 3.5 shale ratio is encountered at 6,850 ft, which indicates a very undesirable hydrocarbon environment below this shallow depth. Although the pressure gradient decreases below the 3.5-ratio depth to the 12,000-ft depth, the environment remains unfavorable. It has been our experience that commercial production is not found under such conditions. In other words, once the 3.5 ratio is reached, additional drilling and expense are unwarranted.

Figs. 10A through 10D show four wells in a multipay field offshore Louisiana. Note that all the productive oil zones and some gas zones are at depths shallower than the depth where the 1.6 cutoff ratio appears. Also note that only gas is present below the 1.6-ratio depth and above that for the 3.5 ratio. The well plotted in Fig. 10D was tested below the depth for the 3.5 ratio and was noncommercial.

The well plotted in Fig. 11 is located offshore Louisiana in an area where deep structures and deep sand development are present, making it a good prospect for exploration. Note that the 3.5 cutoff ratio comes in at about 9,000 ft. Massive sands are found below 10,300 ft to 15,400 ft; however, the 3.5 ratio at 9,000 ft puts these sands in an unfavorable hydrocarbon environment. Many wells have been drilled in this area to test these deep sand structures and all have

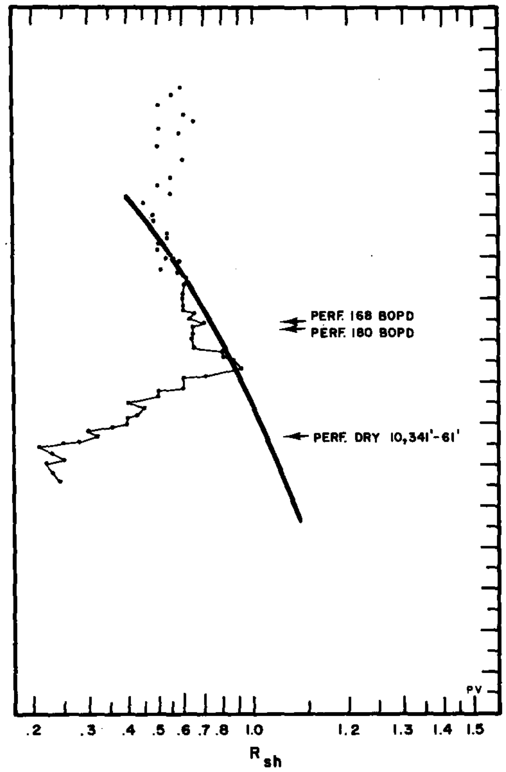

Fig. 10B—Field producer, Offshore Louisiana.

been dry. Based on the fact that the good structures are present, several operators have paid high lease bonuses for this acreage. This particular block cost $4 million, and only a mile away there is a block — with another dry hole on it — that cost $2 million.

Note that on Fig. 11 we have also plotted the depositional environments as determined by the paleontologists. As one would expect, the deepest water deposition coincides with the highest pressures.

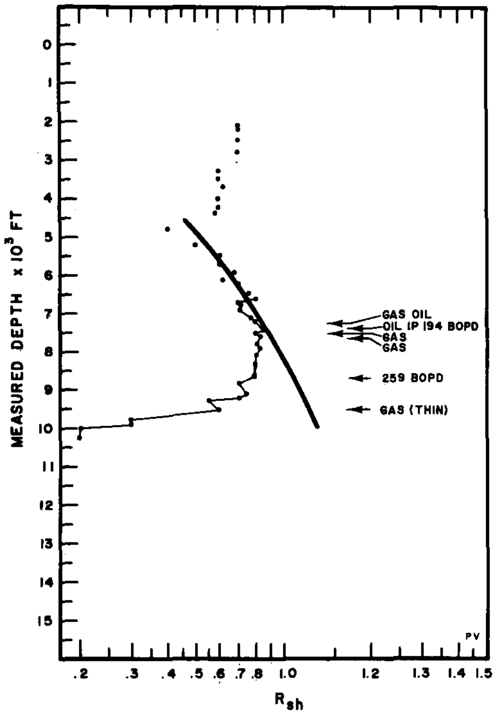

Fig. 10C—Field producer, Offshore Louisiana.

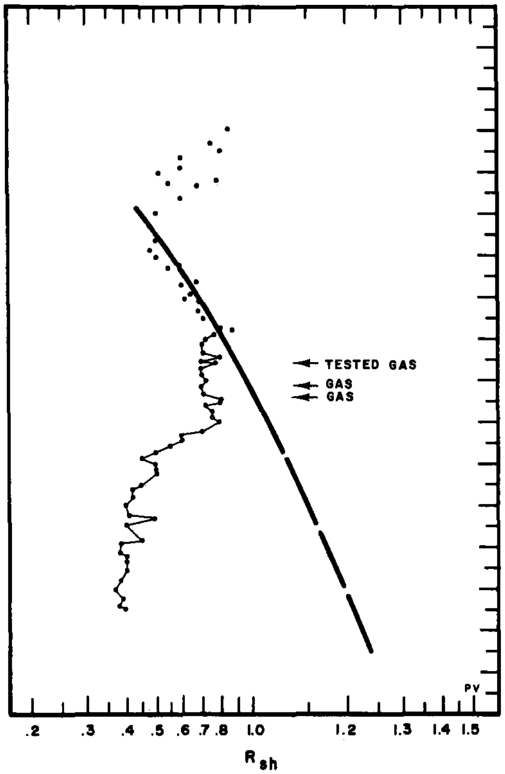

Fig. 10D—Field producer, Offshore Louisiana.

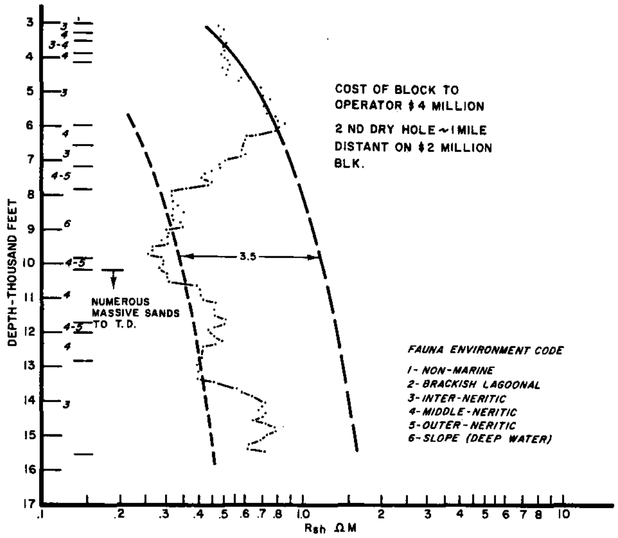

Fig. 11—Area of active exploratory drilling, Offshore Louisiana.

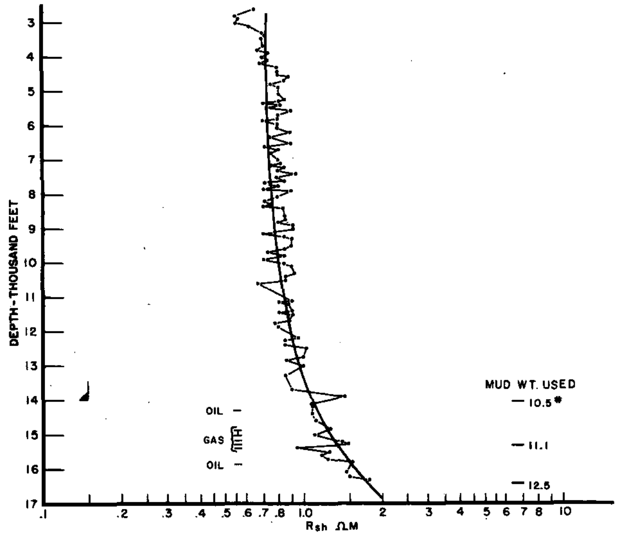

Fig. 12A—Deep oil production, Weeks Island area, Louisiana.

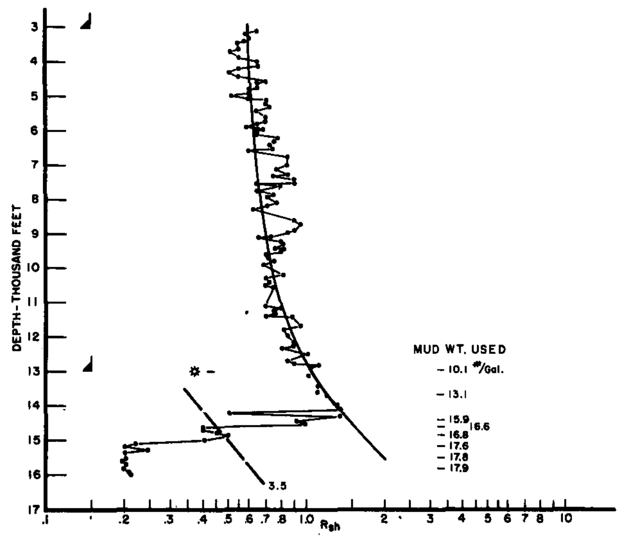

Fig. 12B—Nonprospective deep intervals, Weeks Island area, Louisiana.

Also, as the gradient decreases (as in the interval 13,500-15,400 ft) the depositional environment becomes shallower.

One of the general misconceptions in the drilling industry is that high pressure gradients are associated with extreme depth. This is not necessarily so since essentially normal pore pressure gradients have been found to great depths in certain areas of the Gulf Coast. Such deep horizons are still very good prospects for large oil accumulations. In other words, depth itself is not what determines the presence or absence of large oil reserves. For example, Fig. 12A is a plot for a deep producing oil well in the Weeks Island area of Louisiana. The producing oil zones are as deep as 16,300 ft in this well and have pressure gradients only slightly above hydrostatic gradients. Fig. 12B is a plot for another well in the same field, higher on the structure and about a mile from the well plotted in Fig. 12A. Note that high pressure gradients are encountered just below 14,100 ft. In this well the interval below 14,100 ft would not be prospective for oil, and below 14,600 ft it would not be prospective even for gas; yet these wells are in the same geologic horizons and area.

The wells in Figs. 13A and 13B are deep wells drilled in Iberia Parish and Vermilion Parish, respectively. The production in both instances is above the depth for the shale ratio of 3.5. Statistically, about 50 percent of the well costs in the Gulf Coast have occurred when the wells have reached protection-pipe setting depths such as that for the 9⅝-in. string indicated in Fig. 13A. However, both the wells plotted in Fig. 13 were drilled approximately 4,500 ft deeper through superpressure. These bottom sections of hole are in the unfavorable hydrocarbon environment and the time and expense — to say nothing of the hazards — of drilling these sections are unwarranted.

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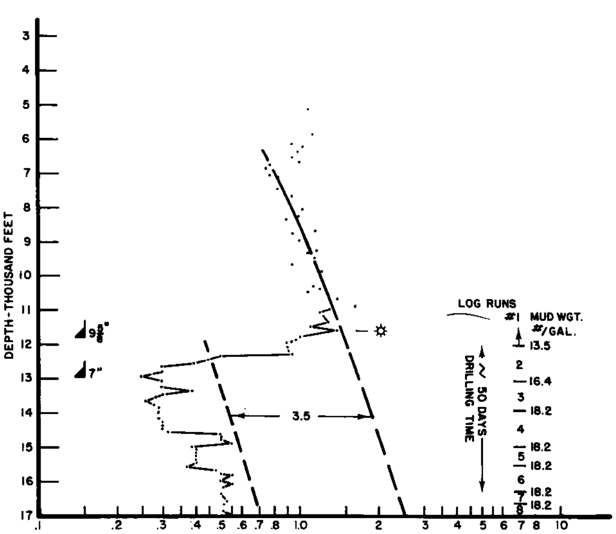

Fig. 13A—Deep, high-pressure environment, Iberia Parish, La.

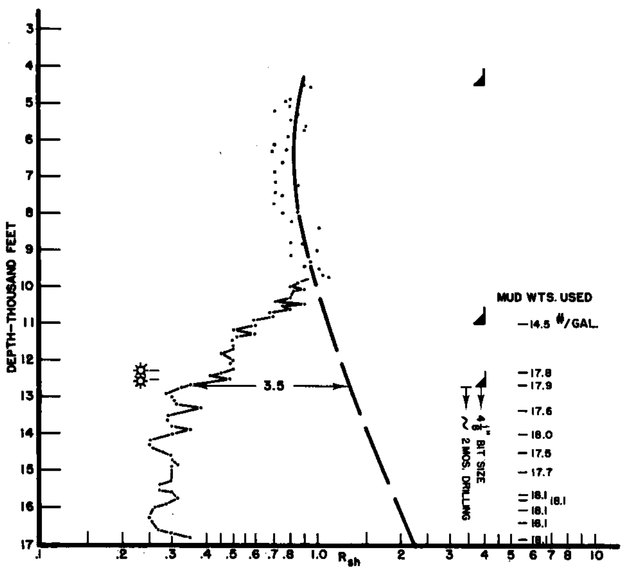

Fig. 13B—Deep, high-pressure environment, Vermilion Parish, La.

Discussion

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This paper represents a significant contribution to our knowledge of the economic factors involved in exploration and development of geopressured reservoirs. As indicated in the paper and the references cited, the high cost of drilling and producing these reservoirs has been recognized for some years. In retrospect, it seems only logical that the radical change in physical conditions observed in the transition from normally pressured to geopressured sediments should be accompanied by changes in the nature and distribution of the associated petroleum. Yet the nature and magnitude of these changes do not appear to have been systematically examined in the past.

The publication of this pioneering work should stimulate additional efforts to define more exactly the relationships among subsurface temperatures and pressures and the occurrence and composition of petroleum. Clearly in need of further investigation is the relationship between pressure gradient and reservoir size. Timko and Fertl indicate that reservoir size decreases as pressure gradient increases within the geopressured section. Other publicly available data suggest that the actual relationship may be more complex than these authors suggest.

An MS thesis by Perry[1] comparing pressure gradients obtained from public records with reservoir sizes obtained from industry sources covers 56 geopressured Southwest Louisiana gas reservoirs. Perry concludes that reservoir size increases with increasing pressure gradient. Although this is the only work applying specifically to this problem, reservoir pressures and reserves estimates for abnormally pressured Louisiana gas reservoirs are available from at least two other sources. Meyerhoff[2] includes a few geopressured reservoirs in the typical gas fields of South Louisiana studied by the Lafayette and New Orleans Geological Societies. Spot checks of Meyerhoff's data suggest that in some cases the pressure given may be lower than the original reservoir pressures. The FPC data[3] provide a much larger sample, covering all South Louisiana gas reservoirs connected to interstate pipelines in 1963. In a few cases, the FPC data — and Meyerhoff's data to a lesser extent — reflect a tendency to separate large reservoirs into smaller, more manageable parts. This causes an apparent tailing off at the larger end of the reservoir size distributions that is at least partially spurious.

Table D-1 summarizes the distribution of reservoirs with gradients in excess of 0.6 psi/ft from each of these sources. The pressure gradients are divided into 0.05 psi/ft increments, and the number of reservoirs and the arithmetic mean reservoir size are given for each increment. The distribution of reservoir sizes is suggested by the literature[4] to be lognormal. Plots of Perry's data on log-probability paper confirm this distribution. The geometric mean is a more representative measure of central tendency for a lognormal distribution; therefore, the geometric mean was calculated for Perry's and Meyerhoff's data. The data from Meyerhoff and the FPC are taken at face value without editing or corrections.

Fig. D-1 is an attempt to define more clearly the exact nature of the distribution of reservoir size with pressure gradients from Perry's data. A moving average reservoir size over a 0.05 psi/ft range is calculated at 0.01 psi/ft intervals. Both the geometric and arithmetic means from Perry's data are plotted in this manner. The arithmetic mean of the FPC data from Table 1 is plotted for comparison.

Table D-1 and Fig. D-1 suggest that reservoir size decreases with increasing pressure gradient up to a pressure gradient of 0.65 or 0.70 psi/ft. In the 0.70-0.85 psi/ft range, reservoir size appears to increase with increasing gradients. At pressure gradients greater than 0.85 psi/ft, there is a suggestion from Perry's data that reservoir sizes decrease with increasing gradients. Meyerhoff's data in this range of pressure gradients are inadequate. The FPC data show a continued increase, but there is some reason to believe that with careful editing and more detailed statistical work, the FPC data might conform better with Perry's data.

Basically, these data appear to support Timko and Fertl's concept of a decrease in reservoir size with increasing gradient between Zones A and B (see their Fig. 4) and to contradict their concept of a decerase in reservoir size with increasing pressure gradients

TABLE D-1—AVERAGE RESERVOIR SIZE BY PRESSURE GRADIENT

Source	Datum	Pressure Gradient Range (psi/ft)						
		0.60-0.65	0.65-0.70	0.70-0.75	0.75-0.80	0.80-0.85	0.85-0.90	0.90+
Perry[1]	Number of reservoirs	3	3	19	10	12	7	2
	Geometric mean reservoir size (BCFG)	18.7	6.4	8.1	4.6	43.6	18.0	21.9
	Arithmetic mean reservoir size (BCFG)	49.8	8.1	47.0	10.8	131.1	53.4	97.2
Meyerhoff[2]	Number of reservoirs	2	1	2	3	5	1	1
	Geometric mean reservoir size (BCFG)	22.9	13.6	117.0	131.0	18.8	189	170
	Arithmetic mean reservoir size (BCFG)	34.4	13.6	177.1	228.2	155.9	189	170
FPC[3]	Number of reservoirs	49	60	78	55	79	57	23
	Arithmetic mean reservoir size (BCFG)	34	23	32	27	57	42	84

between Zones B and C of their Fig. 4. If Zone D consists entirely of noncommercial reservoirs, its presence should not be reflected on these compilations of producing reservoirs. The apparent decrease in reservoir size at extremely high pressure gradients suggested by Perry's data may be interpreted as supporting the presence of Zone D.

The only point in question, then, appears to be the relationship between reservoir sizes in Zones B and C. The 60 or so reservoirs used by Timko and Fertl provide a sample size comparable with that of Perry. Without more information on the exact nature of the authors' statistical data and techniques, it is impossible to determine the exact cause of this discrepancy in results.

Two possible causes may be (1) sampling bias, and (2) inappropriate statistical techniques. The data presented in Table D-1 and Fig. D-1 are based on compilations of producing reservoirs. As development and production expense increase in higher pressured reservoirs, successively larger reservoirs will become noncommercial. This has the effect of raising the minimum size of the higher-pressured reservoirs included in any compilation of producing wells. This higher minimum commercial size will increase the average size of the producing reservoirs in higher-pressured zones. A check of the values of the lower quartile from Perry's data suggests that this process is not adequate to account completely for the discrepancy in results, but this cannot be considered to be conclusive.

If Timko and Fertl's data include a number of reservoirs that were never officially completed and produced, they may be more representative of the true distribution of reserves than the data presented in Table D-1 and Fig. D-1. This possibility could be checked by omitting from Timko and Fertl's sample the reservoirs that were never produced. The distribution of reservoirs that were actually completed should then be more comparable with that shown on Table D-1 and Fig. D-1.

Another, more remote, possibility is that the authors may have been misled by the use of an inappropriate measure of central tendency, such as the arithmetic mean. The arithmetic mean of a lognormal distribution is very sensitive to the presence of large reservoirs in a sample. It is conceivable that a few large reservoirs could have caused a variation in arithmetic mean that masked the true distribution of reservoir

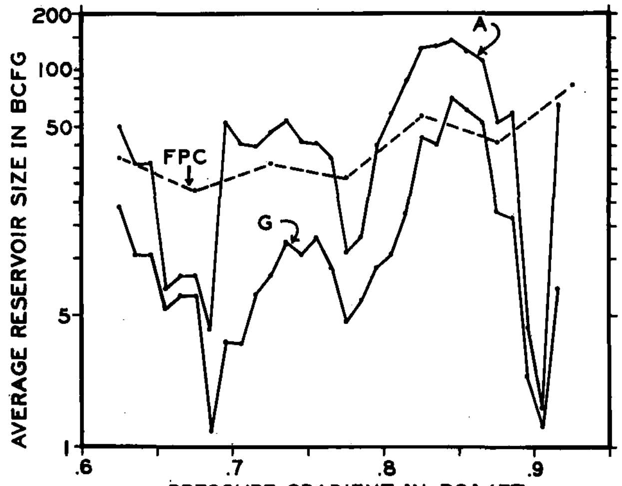

Fig. D-1—Average reservoir size by pressure gradient from Perry's data.[1] Geometric mean and arithmetic mean plotted as a 0.05 psi/ft moving average for every 0.01 psi/ft increment. Lower line, G, is geometric mean; upper line, A, is arithmetic mean of same data. Dashed line is arithmetic mean of FPC[3] data, Table D-1.

size. This possibility could be readily checked by calculating the geometric mean from Timko and Fertl's data.

The possible causes of these discordant results that are listed above can be readily checked. In the absence of the basic statistical data, there may be other causes that are not apparent. A more detailed statistical study of the FPC data, using appropriate statistical measures and editing procedures, might help clarify this problem.

References

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Authors' Reply to Discussion

We appreciate Fowler's discussion and constructive criticism, and the opportunity to further clarify the main points of our paper, which apparently are not quite understood. We also agree that we have just scratched the surface in determining the complex relationships between the formation pressure and temperature environment and types of hydrocarbons and the producibility of these hydrocarbons.

As Fowler points out, there is considerable information available relating reservoir size and formation pressure gradients. Also, as he has mentioned, any conclusions drawn from these relationships may be affected by using inappropriate statistical techniques and sampling bias, which is the pitfall he believes we could have stumbled into. However, what we have attempted to do in our paper is to eliminate

these difficulties and bias by not relating to pressure gradients at all, but strictly to the well log shale resistivity ratio. This ratio is best expressed by our Fig. 4, which has been developed over the past few years by analyzing hundreds of wells — both commercially and noncommercially productive — in all ranges of pressure. Clearly and simply stated, and irrespective of measured formation pressure gradients, the following conclusions can be drawn from our paper:

1. Most commercial oil sands exhibit shale resistivity ratios less than 1.6 in shallower shales above them and generally can be reached without a string of protection pipe.
2. Most commercial gas sand reservoirs exhibit ratios in shales above them of approximately 3.0 and less. These wells can have extremely high measured pressure gradients, and could be the large high pressure gradient reservoirs discussed by Fowler and Perry. For instance we note that in the East Cameron area, a resistivity ratio of 2.8 is equivalent to a gradient of 0.9 psi/ft (see Fig. 5). Even with this high a gradient we have established the presence of very large reservoirs in the East Cameron area.
3. Wells with ratios between 3.0 and 3.5 can be commercially gas productive and generally will produce as one- or two-well reservoirs. It must be pointed out here that this situation could develop in large fields that are highly faulted, with the faults themselves limiting the size of individual reservoirs.
4. No commercial production is found when the shale resistivity ratio reaches or exceeds 3.5, no matter what the actual pressure gradient is. These wells often are highly productive initially and are characterized by extremely fast pressure depletion. Further, we have not found commercial production in any well below the depth where the 3.5 ratio exists even though ratio drops below 3.5.

We hope that this short reply to Fowler's discussion helps to clear up some of what he feels are discordant results. Such discrepancies, we understand, would be hard to completely dispell in any statistical type of analysis such as this. Further, the mere fact that we have attempted to simplify very complex pressure and hydrocarbon relationships using readily available well log parameters inherently tends to make one suspicious of the results. The only way to measure the worth of our paper is to test the resistivity ratio concept against known pressure environments and then to draw one's own conclusions. **JPT**